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Participation of wind power plants in system frequency control: Review of grid code requirements and control methods

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ABSTRACT

Active power reserves are needed for the proper operation of an electrical system. These reserves are continuously regulated in order to match the generation and consumption in the system and thus, to maintain a constant electrical frequency. They are usually provided by synchronized conventional generating units such as hydraulic or thermal power plants. With the progressive displacement of these generating plants by non-synchronized renewable-based power plants (e.g. wind and solar) the net level of synchronous power reserves in the system becomes reduced. Therefore, wind power plants are required, according to some European Grid Codes, to also provide power reserves like conventional generating units do. This paper focuses not only on the review of the requirements set by Grid Codes, but also on control methods of wind turbines for their participation in primary frequency control and synthetic inertia.

Contents

1. Introduction

For the stable operation of an electrical network, system frequency control is decisive. It ensures a continuous adaptation of power generation to power consumption. The power balance in

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the electrical network is interrelated to the network frequency via all synchronous generators connected to it; e.g. an increase in the load decelerates the synchronous generators and thus leads to a frequency drop. As frequency is uniform throughout the interconnected network, it is convenient to use it as a control variable for a decentralized control system: the network frequency control. It makes use of the power plants in the network, which – according to their abilities and agreements – adapt their active power feed-in according to the current system requirements. Thus, the power plants involved require a certain level of active power reserves. Traditionally and still typically, it is conventional generation plants, like hydroelectric and thermal power plants, which are used for frequency control. The ability of a system to maintain its frequency within a certain tolerance band is called frequency stability.

Another important function of conventional power plants for frequency control is the passively provided so-called *instantaneous power reserve*. Any imbalance between power generation and consumption is instantaneously balanced due to the physical principle of the synchronous generator. The large inertia of the rotating generator set works as a buffer storage, any usage leading to the mentioned change in rotational speed and thus in system frequency. The larger the synchronized inertia in the system, the slower the change of frequency [1].

The stepwise replacement of conventional generating units by wind and photovoltaic power plants will have a significant impact on the system frequency behavior. First, the grid loses the active power reserves of conventional plants. And second, it loses instantaneous power reserves, because wind turbine generator sets are operated decoupled from system frequency, which allows for aerodynamically efficient operation. In detail, the turbine's synchronous or asynchronous generators are connected to the grid via fast controlled power electronics [2–4].

The studies by the Irish regulator set out that system frequency stability could be compromised with 60–70% of the total instantaneous power generated from wind power plants [5].

In order to maintain system frequency stability in a network with an increasing share of wind power, wind turbines will have to take on more and more tasks of conventional power plants related to frequency control. This is reflected by a gradual development of more stringent requirements by system operators in regard to the integration of wind power plants into network frequency control [6]. According to some system operators, e.g. the Irish operator [7], wind power plants are already required to provide power reserves. Also, future regulations will appear with the development of new requirements regarding synthetic inertia by wind power plants [6].

Even though the power output of wind turbines depends on the unreliable and difficult-to-predict wind speed and the generator set does not provide a passive instantaneous power reserve, there are methods for wind power plants to actually provide power reserves and thus to participate in grid frequency control. Such abilities will be crucial for the successful integration of wind power plants into the grid.

This work presents a review of selected European Grid Codes and future trends regarding the tasks of wind power plants related to participation in frequency control. It also offers a literature review of the proposed methods for enabling wind turbines to provide active power reserves. Furthermore, the possibilities of wind turbines to provide instantaneous reserves are discussed.

2. Review of European Grid Codes regarding participation in frequency control

Due to the island situation of Ireland and the UK, frequency control is a particularly challenging task in these electrical networks since they do not have access to the large power reserves in the interconnected network of continental Europe. Thus, requirements for wind power plants are significantly stricter in these networks than in the continental grid. However, the rising share of wind power will also lead to stricter requirements in continental Europe.

Accordingly, this section firstly gives the definition and nomenclature for different types of active power reserves. Secondly, deployment times of power reserves for selected European grid codes are depicted. Then, particular requirements for wind power plants regarding frequency control according to the grid codes of Ireland and the UK are presented. Finally, future trends based on the latest ENTSO-E's Network Code [6] are discussed.

2.1. Nomenclature and definition of power reserves

Power reserves can be defined as the additional active power (positive or negative) that can be delivered by a generating unit in response of a power unbalance in the network between generation and consumption. Four different reserve levels can be defined: *instantaneous, primary, secondary and tertiary power reserves* [11]. This terminology is widely accepted; however nomenclature can vary from one country to another. The following contents provide the definition of each power reserve.

The *instantaneous power reserves* refer to the physical stabilizing effect of all connected synchronous generators due to their inertia. In the event of a generation drop in the network, the instantaneous reserves balance the power due to this stabilizing and passive effect. Their electrical power P_{elect} rapidly increases, which provokes an electromechanical unbalance in the generator set according to

$$P_{mech} - P_{elect} = J\omega_g \frac{d\omega_g}{dt}, \tag{1}$$

P_{mech} being the developed mechanical power by the generator, J is the moment of inertia referred to the generator shaft and ω_g is the mechanical speed of the generator (the electrical rotational speed of the generator ω_r is deduced from the number of poles p and ω_g as

$$\omega_r = \omega_g \frac{p}{2}. \tag{2}$$

As a result of the power imbalance, the rotational electrical speed ω_r decreases. This reduction is also in the interrelated frequency of the system. The rate of change of system frequency (ROCOF) depends on the amount of available instantaneous power reserves and thus on the inertia of the system [3]. Low levels of system inertia, i.e. high levels of ROCOF, can provoke the tripping of sensible loads, generating units and relays (implemented to avoid islanding [5]), thus affecting system frequency stability.

For power system related studies, it is a common practice to define the inertia constant H. The inertia constant, in seconds, determines the duration in which the generating unit theoretically may provide its rated power only using the kinetic energy stored in its rotating parts. It can be mathematically expressed as half of the mechanical acceleration time constant τ_{acc} (in seconds),

$$H = \frac{1}{2}\tau_{acc} = \frac{1}{2} J \frac{(\omega_g^{nom})^2}{P_{nom}^{total}}, \tag{3}$$

where ω_g^{nom} is the nominal mechanical generator speed in rad/s, P_{nom}^{total} is the nominal power of the generating unit, and J is the moment of inertia in kg m^2, referred to the generator shaft. The reader is referred to [1] and [15] for further details regarding the definition of inertia constant. It is important to note that wind turbines do not have inertia from the electrical system point of view, since the rotor is not synchronized with the network but connected through power electronics. According to [3], ROCOF

increases under system frequency disturbances as wind generation displaces conventional generation due to the decoupling of the rotor of the generators by their fast controlled power electronics [1]. However, it does not happen with squirrel-cage asynchronous generators, since they provide a naturally inertial response being directly connected to the grid [17].

Primary reserve is intended to be the additional capacity of the network that can be automatically and locally activated by the generator's governor after a few seconds at most of an imbalance between demand and supply of electricity in the network [11]. The aim of primary reserve is to quickly balance the consumed and generated power in the system and thus stabilize frequency at a certain level. These primary reserves are typically activated automatically by frequency droop controllers of generating units, building up the so-called *primary frequency control*. Primary reserves must be delivered until the power deviation is completely offset by *secondary* or *tertiary reserves*. With the aim of harmonizing the nomenclature related to power reserves, in June 2012 the European Network of Transmission System Operators for Electricity ENTSO-E, which is the association of Transmission System Operators (TSOs) in continental Europe, defined primary reserves as *frequency containment reserves* [10]. Prior to the publication of this document, in ENTSO-E's "Operational Handbook" [11], this reserve level had been set as a *primary control reserve*. The present document considers both abovementioned publications (due to their complementary and non-exclusive character) to depict the ENTSO-E's recommendations regarding system frequency control and reserve power levels.

Secondary reserves are activated to restore the rated frequency of the system, releasing primary reserves, and to restore active power interchanges between control areas to their set points [11]. They are activated by the TSOs by modifying the according active power set points of the generating units within each respective control area. In June 2012, the ENTSO-E proposed the term *frequency restoration reserves* for defining secondary reserves [10].

Finally, the aim of *tertiary reserves* (or *replacement reserves* according to the last proposal of the ENTSO-E [10]) is to replace the secondary reserves and restore frequency to its rated value if secondary reserves were not sufficient. Furthermore, they are used for economic power dispatch [9], considering system constraints such as current limits of transmission lines. These reserves are activated manually and centrally at the TSO's control centers in the case of observed sustained activation of secondary reserves or to anticipate a response to expected unbalances [11].

General rules and technical recommendations regarding reserve power levels and their associated control performance are set in the ENTSO-E's "Operational Handbook" [11]. Despite these general guidelines, specific rules for the provision and control of power reserves for grid frequency control must be determined by the TSOs in their own Grid Codes.

2.2. Deployment sequence of power reserves for frequency control

Fig. 1 depicts the principle behavior of system frequency after a sudden lack of power generation in the network with all mentioned power reserve levels being involved. Some annotations on their activation are included according to [11].

In the event of a generator trip in the network, the system frequency starts dropping and thus the instantaneous reserves of the synchronous generating units help to recover the power balance in the network due to the stabilizing effect of the inertia. Then, as soon as a certain frequency level is reached, the primary power reserves are activated; the generators' driving mechanical power rises. As the equilibrium between the developed electrical and mechanical power in the generators is achieved, the system frequency stops dropping, i.e. the frequency nadir is achieved. Next, a further increase of primary reserve power accelerates the generator sets and the system frequency rises up to a new steady state below its rated value.

The slope of the primary power-frequency droop characteristic has a major influence on the achieved frequency nadir and the stabilization level of frequency [1,16]. In this sense, it can be concluded that the slower the governor response of the generating unit, the lower the frequency nadir.

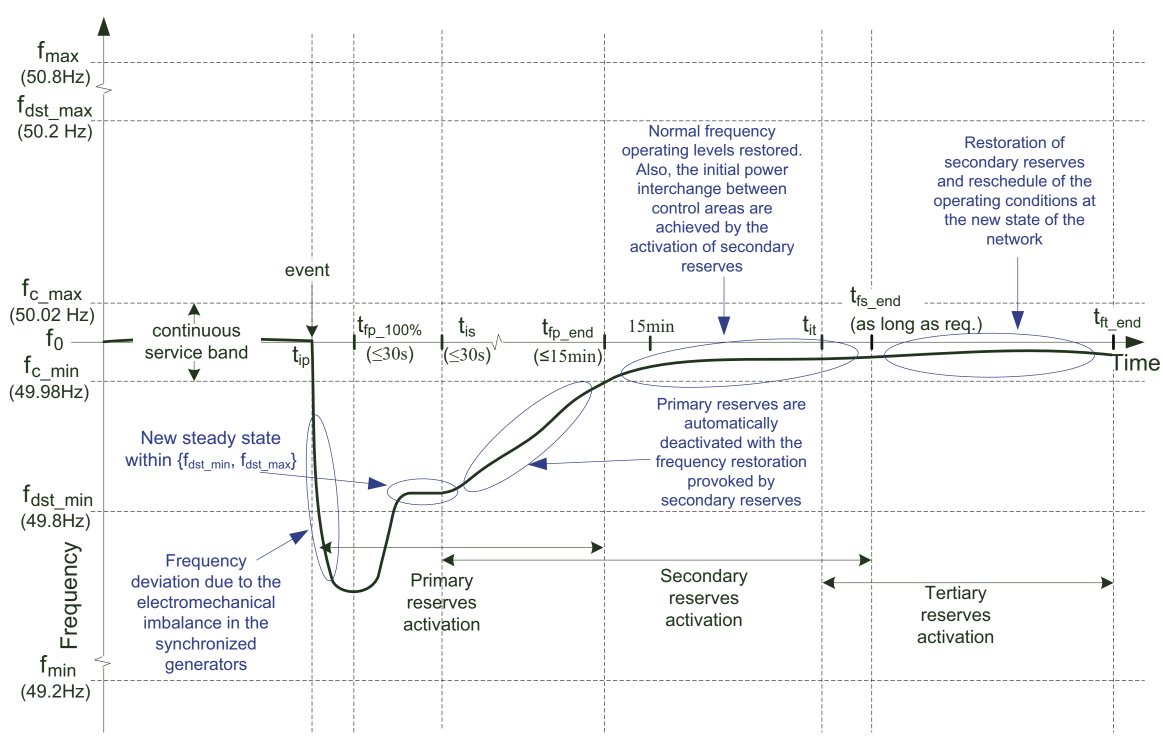

Fig. 1. Concepts definition (particular values of time frames and frequencies are according to the recommendations of ENTSO-E [11]).

The activation of secondary reserves recuperates the normal operating frequency levels and thus the deactivation of primary reserves. Secondary reserves are operated until they are fully replaced by tertiary reserves. Proper explanations of the parameters presented in Fig. 1 are listed as follows: [11]:

- f_{min} and f_{max}: Minimum and maximum expected instantaneous frequency after a reference incident (loss of generation or loss of load) assuming predefined system conditions.
- f_{dst_min} and f_{dst_max}: Minimum and maximum steady state frequency. They define the tolerance band for the quasi-steady-state system frequency after the occurrence of a reference incident, assuming predefined system conditions. Outside this interval, all available primary reserves stay activated. This means that droop controllers of all units providing primary reserves should be set for deploying all their contracted or obligatory primary reserve capacity.
- f_{c_min} and f_{c_max}: Limits of the frequency dead-band for the activation of primary reserves. These limits define an interval in which primary reserves are not required to be activated. This allowed frequency deviation usually corresponds to the accuracy of the frequency measurement and the insensitivity of the controller. That notwithstanding, a greater dead band is also permitted in accordance with TSO.
- t_{ip}, t_{is} and t_{it}: Maximum starting time for the activation of primary, secondary and tertiary reserves from the event detection time.
- $t_{fp\_50\%}$ and $t_{fp\_100\%}$: Maximum deployment time for 50% and 100% of total primary reserves from the event detection time, respectively.
- $t_{fs\_100\%}$ and $t_{ft\_100\%}$: Maximum deployment time for 100% of total secondary and tertiary reserves from the event detection time.
- t_{fp_end}, t_{fs_end} and t_{ft_end}: Minimum capability of actuation of primary, secondary and tertiary reserves.

Accordingly, Table 1 presents specific values of the above-listed frequency levels and time frames from ENTSO-E's recommendations in its Operational Handbook [11], as well as particular data from selected European Grid Codes. It must be noted that the indicated values apply to conventional generating units participating in system frequency control.

As can be noted in Table 1, the specified frequency levels in both German [18] and Spanish [19,20] Grid Codes mainly match with the recommendations of ENTSO-E [11]. In fact, the deployment sequence for power reserves do not differ essentially from one country to another within the interconnected continental European networks. This permits us, for instance, to conclude that primary reserves are required to be fully activated 30 s at most after the frequency deviation detection in continental European networks.

The deployment sequence for power reserves in islanded grids is quite different from those for continental European networks. For instance, the Irish Grid Code requires a faster response time in full activation of power reserves (see Table 1). Despite the fact that the authors of this work were not able to find a particular value for the response time in full activation of primary reserves in the Irish Grid Code, the activation time of secondary reserves is set to 5 s at most after the frequency deviation detection, which is a shorter time than that provided for the full activation of primary reserves in continental European networks. Further, it is remarkable that the concept of secondary reserve does not exist in the UK's electrical network, distinguishing themselves from the rest of the European networks considered. That is because the frequency control in this network is done just using the primary governors of the generators.

Table 1
Parameters extracted from ENTSO-E's recommendations and some European Grid Codes for conventional generating units participating in system frequency control.

Parameter	ENTSO-E (2009) [11]	German Grid Code (2007) [15]	Spanish Grid Code (1998, 2009) [16,17]	Irish Grid Code (2011) [7]	UK Grid Code (2012) [18]
f_0	50 Hz	50 Hz	50 Hz	50 Hz	50 Hz
$\{f_{c\_min};f_{c\_max}\}$	{49.98;50.02} Hz	{49.98;50.02} Hz	{49.98;50.02} Hz	{49.985;50.015} Hz	{49.985;50.015} Hz
$\{f_{dst\_min};f_{dst\_max}\}$	{49.8;50.2} Hz	{49.8;50.2} Hz	{49.8;50.2} Hz	{49.5;50.5} Hz	{49.5;50.5} Hz
$\{f_{min};f_{max}\}$	{49.2;50.8} Hz	{49.2;50.8} Hz	{49.2;50.8} Hz	{49.0;51.0} Hz	{49.2;50.8} Hz
t_{ip}	A few seconds after detecting a frequency deviation of ± 20 mHz[a]	A few seconds after detecting a frequency deviation of ± 20 mHz[b]	A few seconds after detecting a frequency deviation of ± 20mHz	0 seconds (or with frequency deviation of ± 15mHz)	0 seconds (or with frequency deviation of ± 15mHz)[c]
$t_{fp\_50\%}$	≤ 15 s	–	≤ 15 s[d]	–	–
$t_{fp\_100\%}$	≤ 30 s	≤ 30 s	≤ 30 s[e]	–	≤ 30 s[f]
t_{fp_end}	≥ 15 min	≥ 15 min	As long as required	≥ 30 s	≥ 30 min[g]
t_{is}	≤ 30 s	≤ 30 s	–	≤ 5 s	–
$t_{fs\_100\%}$	≤ 15 min	≤ 15 min	300 s ≤ 500 s[h]	≤ 15 s	–
t_{fs_end}	As long as required	As long as required	≥ 15 min	10 min	–
t_{it}	In TSO's decision	In TSO's decision	In TSO's decision	In TSO's decision	In TSO's decision
$t_{ft\_100\%}$	A short time	A short time	≤ 15 min	–	–
t_{ft_end}	–	–	≥ 2 h15 min	–	–

[a] According to the corresponding document, section A-S2.3. "Physical deployment times".
[b] According to the German Grid Code, section 5.2.2, page 39 [15], and referring to the frequency control, "the TSO shall use primary control power in accordance with the rules of the UCTE-OH Policy 1", that is the document referred to the first column of the table ENTSO-E (2009) [11].
[c] According to the Grid Code of UK, section CC.A.3.4 [18], and referring to the activation of primary reserves, "the active power output should be released increasingly with time over the period 0–10 s from the time of the start of the frequency fall".
[d] The deployment time from 50% to 100% of total primary reserve rises linearly from $t_{fp\_50\%}$ to $t_{fp\_100\%}$.
[e] If network frequency variation is less than 100 mHz, $t_{fp\_100\%} = 15$ s.
[f] This value corresponds to the maximum deployment time of the so-called primary response capability of a generator unit operating in frequency sensitive mode. For more details please refer to Section 2.3.
[g] This value corresponds to the minimum capability of actuation of the so-called secondary responses of a generating unit operating in frequency sensitive mode. For more details please refer to Section 2.3.
[h] Response time constant of 100 s of a 1st order type system.

Apart from setting the deployment times for power reserves, regulations also specify the power reserve needs for each control area of the network, so that the stability of the system can be ensured. The required primary reserves in the synchronized European network to stabilize system frequency are defined from the so-called referent incident. This referent incident is the maximum expected power deviation between generation and consumption in a network. Primary reserves must be able to offset the power unbalance caused by a reference incident. For continental Europe, this referent incident, or primary reserve need, is estimated at 3000 MW [11]. This total power reserve is allocated throughout the network attending to the specificities of the grid of each country.

Usually, the providers of power reserves (mostly primary and secondary power reserves) are power plants with relatively high ramp power rates and short time responses, due to the required fast dynamics for regulating their power output for frequency control related tasks. In this regard, open and combined cycle gas turbine-based power plants as well as hydropower plants are the most suitable technologies.

In fact, hydropower is a mature technology which nowadays represents more than 80% of the total renewable energy generated worldwide. In Germany, as an example, the total hydropower capacity installed is very high, around 4.3 GW, providing principal power reserves for ensuring the stability of the continental European network. Some figures illustrating the high ramp power rates of such installations have been published by First Hydro Company [12]. This company reports the main features of a pumped hydro storage installation able to move from 0 to 1320 MW power output in just 12 s, managing 6 motor-generators of 330 MW activated by reversible Francis water turbines. The major drawbacks of hydropower are the environmental aspects derived from the required civil constructions affecting the natural flow of rivers. The scarcity of suitable sites, which are commonly natural and difficult-to-access areas, to install the power plant and the need of installing new transmission lines to transport the electricity generated to the consumers, are viewed as important environmental impacts to be considered, as well.

Gas turbine-based power plants are also very flexible so they can be activated quickly to provide power reserves when required. They are also used for other purposes, such as providing the service of peak shaving during periods of high demand. Gas turbine-based plants are non-CO_2 neutral power plants, and this is a major drawback for this technology in comparison with hydropower plants. On the other hand, both the capital expenditures and operating and maintenance expenditures of such installations are lower than in the case of hydropower-based, as depicted in [13].

Finally, it is important to note that the valorization schemes for the provision of power reserves can also vary from one country to another according to the different Grid Codes and rules for the different electrical markets. For instance, according to the German Grid Code [18], it is mandatory just for conventional generating units with rated power greater than 100 MW to provide primary reserves to the system. Smaller generators may also be employed upon agreement with the TSO [18]. The participation in this service is remunerated, as the provision of secondary and tertiary reserves. As a difference from the German Grid Code, the Spanish Grid Code [19,20] specifies that all synchronized generators must provide primary reserves but this participation is not paid for. Just the provision of secondary and tertiary reserves is market-regulated.

Each country sets different rules for the operation of its electrical energy markets. Apart from the day-ahead and intraday markets, in which the majority of the electricity consumed daily is negotiated, there are other markets for the provision of power reserves as well as for the provision of other ancillary services to the network. In this regard, and following Spain's example, secondary and tertiary power reserve needs are negotiated in the so-called secondary and tertiary markets. The providers of these reserves participate in the corresponding markets presenting their bids, specifying the offered reserve level (in MW) with the corresponding price (in Euro/MW), for each operating period of the following day. Thus, the assignation of the providers of the reserves is done in advance so as to ensure the provision of enough reserves for the proper operation of the network during the day.

European trends in this regard are devoted to the integration of markets such as the day-ahead, intraday and others for the provision of ancillary services as this is intended to be a source of flexibility for the future European electrical networks [14]. Flexibility is essential for enhancing the accommodation of growing amounts of renewable (and thus variable) generation. Other measures that will transform the markets of the future are, for instance, the reduction of the common hourly basis operation of the electrical markets down to quarter-hourly or even real time basis. This will reduce forecasting errors for the generation and the demand in the network. Forecasting errors compromise the proper dispatch of the generators and the determination of the required power reserve levels.

Previous contents refer to the provision of power reserves by conventional generating units in different European countries. This serves as a starting point for introducing the specificities for the provision of power reserves by wind power plants in the following sections.

Grid Codes of islanded European networks, such as those for the networks of Ireland and the UK, set specific requirements for renewable generating units regarding the provision of primary reserves in both directions of frequency deviations. In contrast, in other continental European networks with a high penetration of renewable-based power plants, as in the case of Germany and Spain, current Grid Codes do not require renewable generating units to provide primary reserves for their participation in frequency control related tasks. Nevertheless, renewable generating units within the German network are required to reduce their output for frequency control purposes at system frequencies above 50.2 Hz[1] and also they can, but are not required to, provide primary reserves [22].

Accordingly, the subsequent sections set out the most relevant aspects regarding system frequency control support by wind power plants in keeping with the Irish and UK Grid Codes [7,21]. A brief note about secondary reserves according to the Irish regulation is also included as it is considered particularly interesting for the purpose of this article.

2.3. Detailed view on requirements for wind power plants by the Grid Code of Ireland

The Irish regulation details, among other contents, a specific set of requirements for wind power plants regarding some aspects concerning their controllability and behavior during grid disturbances and participation in frequency and voltage control. There are some differences between the ENTSO-E [10] and the Irish terminology regarding power reserves. The Irish Grid Code adopts the term *operating margin*. It represents the power reserve to be sustained to meet the expected system demand for limiting and correcting system frequency deviations. The *operating margin* includes the so-called *operating reserve*, *replacement reserve*, *substitute reserve* and *contingency reserve*. The operating reserve is defined as “the additional power output provided by generating

[1] In the transmission code, section 3.3.13.3, page 35 in the German version, picture 3.4.

ENTSO-E's terminology		Spain	Germany	UK	Ireland	
2009 [11]	2012 [10]	1998, 2009 [19,20]	2007 [18]	2012 [21]	2011 [7]	
Primary reserves: Reserves that are automatically and locally activated while a frequency deviation occurs	**Frequency containment reserves**	**Primary reserves**	**Primary control power**	**Reserves for primary, secondary and high frequency response**	**Primary operating reserves** Time frame: 30 seconds from event	Reserves taking part in "frequency control" under the time scales… "primary frequency control" (up to 30 s after event)
Secondary reserves: Reserves that are automatically or manually activated by TSO a certain time after a frequency deviation occurs, and required for generating units of a control area	**Frequency restoration reserves**	**Secondary reserves**	**Secondary control power**	*This concept does not exist in the UK Grid Code*	**Secondary op. Reserves**: fully available from 15 s to 90s after event **Tertiary op. Reserves**: ***- Band 1***: fully available from 90s to 5 min after event **Tertiary op. Reserves:** ***- Band 2***: fully available from 5 to 20 min after event	and "secondary frequency control" (from 5 s to 10 min after event)
Tertiary reserves: Reserves that are manually activated by TSO in case of observed sustained activation of secondary reserves or in response to an expecte unbalance	**Replacement reserves**	**Tertiary reserves**	**Minutes reserve power**	**Operating and contingency reserves**	**Replacement reserves**: fully available from 20min to 4h after event **Substitute Reserves**: fully available from 4 h to 24 h after event **Contingency reserves**: fully available from 24h to "a limited time scale" after event	Requirements for wind power plants and conventional synchronized generating units with rated power greater than 2 MW

Fig. 2. Equivalences between ENTSO-E (2009) [11], ENTSO-E (2012) [10] and Irish [7] regulations. Equivalences with the Spanish, German and the UK Grid Codes are also depicted.

units realizable in real time operation to limit and correct system frequency deviations to an acceptable level". This operating reserve consists, in turn, of *primary operating reserve*, *secondary operating reserve*, *tertiary operating reserve band* 1 and *tertiary operating reserve band* 2. Each of these operating reserves applies over different time frames up to 20 min following an event.

Moreover, and continuing with the description of terminology differences, frequency control is carried out by means of using the operating reserves and occurs in two time scales: *primary frequency control* and *secondary frequency control*.

Fig. 2 summarizes the equivalences between the ENTSO-E's and Irish terminologies regarding power reserves. Moreover, it also depicts the equivalences with the different terminologies adopted by the rest of the European Grid Codes considered in this paper. According to the Irish terminology, wind power plants are required to participate in system frequency control with the provision of primary reserves and secondary reserves.

As set in Table 1, primary reserves take place in the period of up to 30 s after the detection of a frequency deviation. They are achieved by automatic corrective responses, which include governor droop actions of generators and automatic load shedding. Only synchronous-machine based power plants with rated power greater than 60 MW have to regulate their primary reserves considering a frequency deviation between 49.8 Hz and 50.2 Hz. In contrast, a wind farm control system shall present the capabilities according to Fig. 3 regarding the activation of primary reserves. Points P_A to P_E, and f_A to f_E are determined by the TSO before the start of operation of the unit. The power reserves activation is carried out by automatic local controllers. As can be noted, at rated system frequency, a wind power plant is required to feed in less than its available active power. This derated operation allows the wind power plant to provide both positive and negative power reserves, i.e. to ramp power both up and down in response to system frequency deviations. The primary reserves should be activated immediately after detecting a frequency deviation from the specified dead band without any control signal from the TSO.

Secondary reserves come into play in the time range from 5 s up to 10 min after detecting the frequency deviation. Secondary frequency control is carried out by a combination of automatic and manual actions (dispatch instructions from TSO). Its active power

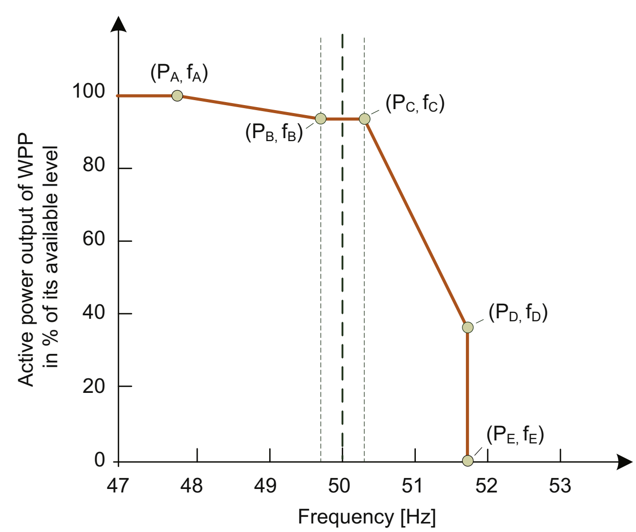

Fig. 3. Droop characteristic for primary reserves activation according to requirements set by Irish regulation for wind power plants [7].

set point comes from the TSO. A time delay of up to 10 s from receiving this set point is allowed for their activation.

As for active power ramp rates for both primary and secondary reserves activation, the response rate of each available wind turbine shall be at least 1% of its rated capacity per second. Moreover, the TSO limits the active power ramp rate to the wind power plant. In this sense, it shall be possible to vary the active power ramp rate between 1 MW/min and 30 MW/min.

2.4. Detailed view on requirements for wind power plants by the Grid Code of the United Kingdom

Each wind power plant (both onshore and offshore) with a registered capacity over 50 MW must be capable of participating in frequency control by continuously adjusting its active power output. This active power control can be performed by applying two operating modes, the so-called *frequency sensitive mode* and *limited frequency sensitive mode*.

In the latter operational mode, the generating units must be capable of maintaining a constant level of active power output for system frequency changes between 49.5 Hz and 50.5 Hz. In the case of wind power plants, the active power output shall be independent of the system frequency in this range. Moreover, below 49.5 Hz to 47.0 Hz, a possible active power drop due to frequency decay shall not exceed 5%. This operating mode applies to wind power plants with rated capacity both less and greater than 50 MW.

The participation in frequency control according to frequency sensitive mode is part of the formulated ancillary services, which are categorized into the so-called *system ancillary services* and the *commercial ancillary services*. System ancillary services refer to the provision of mandatory services in respect of reactive power and frequency control support. Commercial ancillary services include aspects related, for example, to the fast start capability, black start capability and the programmed tripping of generating units to prevent abnormal system conditions such as over voltage and system instability caused by, for instance, system faults.

Therefore, by performing the frequency sensitive mode, wind power plants provide a system ancillary service. Only wind power plants with rated power greater than 50 MW must have the capability of providing this ancillary service, and thus no longer be operated in limited frequency sensitive mode, but in frequency sensitive mode from the TSO's instruction.

The term frequency sensitive mode is the generic description of an operation mode which includes the provision of the *primary response*, and/or *secondary response* and/or *high frequency response*. The so-called primary and secondary responses refer to negative frequency deviation, while the high frequency response refers to positive frequency deviations. These frequency response capabilities are activated by automatic controllers in the generating unit. Consequently, and according to the terminology used in this document, primary, secondary and high frequency response capability can be intended as primary reserves. Each response capability must be tested by inducing a ramp from 0 to 0.5 Hz change over a ten second period to the frequency control device. This frequency deviation must be sustained thereinafter.

Primary response capability of a generating unit is the minimum increase of active power between 10 and 30 s after the start of the induced frequency deviation ramp to the controller. Secondary response capability is the minimum increase of active power output between 30 s and 30 min after the activation of this ramp. Finally, high frequency response capability is the decrease in active power output within 10 s after the induction of, in this case, a frequency ramp with positive slope. These concepts are depicted in Fig. 4.

Being operated in frequency sensitive mode, wind power plants should not extract the maximum available power from the wind but instead have to be derated, so that they can ramp up their output and down according to the frequency of the network. The minimum power output change required of a wind power plant operated in frequency sensitive mode can be found in Fig. 5.

As shown, the change in the generation level depends on the actual loading of the unit. A generating unit must be capable of providing frequency response at least up to the indicated boundaries depending on its loading. Since the indicated power change levels correspond to a frequency deviation of 0.5 Hz, a directly proportional change of power level has to be determined for smaller frequency deviations, i.e. according to a power–frequency droop control. For instance, considering that the wind speed is such that the wind turbine could generate 75% of its registered capacity (i.e. the loading is 75%), it should be operated derated enough to be able to ramp up their power output up to 10% of its registered capacity for primary and secondary responses (see Fig. 5).

Moreover, in Fig. 5, two operational limits are highlighted: the *designed minimum operating level* and the *minimum generation level*. The latter defines the minimum stationary part-load level at

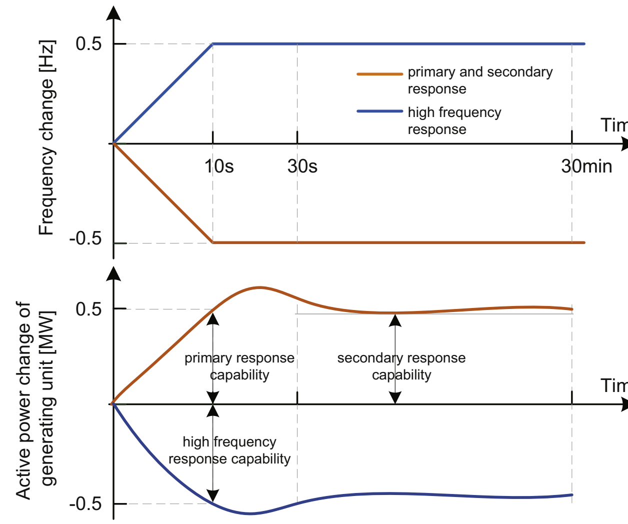

Fig. 4. Representation of primary, secondary and high frequency response capabilities according to UK Grid Code [21].

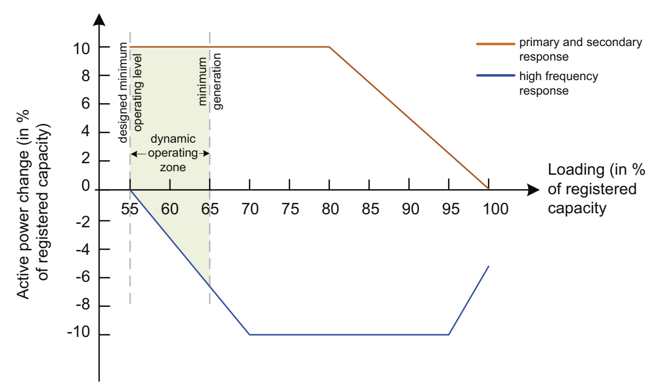

Fig. 5. Minimum active power regulation levels for primary, secondary and high frequency response capabilities (i.e. primary reserves activation) for wind power plants in the event of a system frequency deviation of 0.5 Hz according to UK Grid Code [21].

which the generating unit must be capable of remaining. This level should not exceed 65% of the rated power (see [21], page CC-68 for further explanations). For instance, a wind turbine, or a thermal power plant, must be capable of working at 65% or 60% of its rated capacity in steady state. The former concept, the designed minimum operating level, bounds the minimum generation level at which the generating unit must provide high frequency response, i.e., must activate negative primary reserves at grid frequencies above 50.0 Hz. The generating unit would also have to provide high frequency response under the designed minimum operating level but only under frequencies above 50.5 Hz. Besides, it should be noted that the deadband of frequency control devices in frequency sensitive mode must be ± 0.015 Hz at most.

From Fig. 5, and as previously noted, we can conclude that in frequency sensitive mode, similar to the Irish case, a continuous power derating should be applied to wind power plants in order to be able to transiently increase their output according to the requirements of provision of primary reserve (provided that no energy storage devices are included in the wind power plant).

2.5. Future trends regarding the provision of primary reserves and synthetic inertia by wind power plants

In order to harmonize the connection requirements for generating units of the European power system, ENTSO-E presented

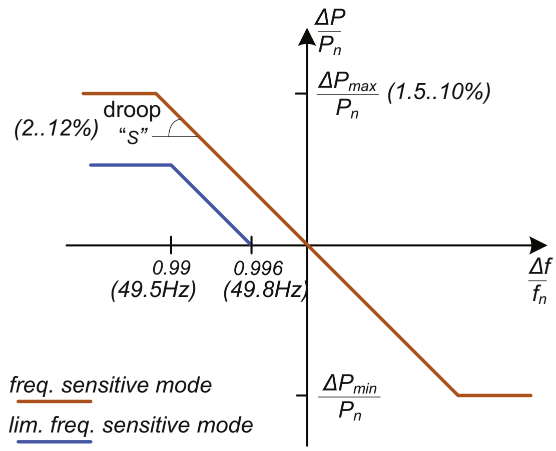

Fig. 6. Active power frequency response droop characteristic according to ENTSO-E's network code [6].

its first network code [6] in June 2012 (see Section 2.1). The network code applies to all grid-connected generators. Generating units are classified in different types according to the voltage level at their grid connection point and their rated power and region. In spite of not explicitly referring to the terms primary, secondary and tertiary reserves, the network code details specific requirements for generating units regarding their participation in frequency control.

Most restrictive requirements regarding frequency control are borne by the generating units categorized type C. This category covers, for instance, wind power plants with rated power above 50 MW in continental Europe, above 10 MW in the UK and above 5 MW in Ireland. These wind power plants must be equipped with a power control system for frequency response. There are two operation modes for this control system: the *limited frequency sensitive mode* and the *frequency sensitive mode*.[2]

In the latter operating mode, the control system is in charge of ramping the active power output of the generating unit up and down in the case of over and underfrequency, according to a power-frequency droop characteristic. The *limited frequency sensitive mode*, as a particular case, just requires the generating unit to increase its power output while frequency lies between 49.5 and 49.8 Hz. These concepts are depicted in Fig. 6.

As shown, in *frequency sensitive mode* a wind power plant must be capable of regulating its power output according to the system frequency within a given range around the currently available power. The required range can be defined between 1.5 and 10% of the nominal power of the plant. The droop characteristic is saturated at predefined frequency levels, which must be determined in accordance with the relevant TSO. The droop characteristic must present a slope comprised between 2 and 12% and could include a deadband up to 0.5 Hz (in accordance with the relevant TSO). Finally, taking into account inevitable frequency measurement errors, there is a tolerance for frequency measurement of 10–30 mHz. The maximum admissible time delay for the activation of primary reserves must be determined in accordance with the relevant TSO (in the network code on page 20 Table 4, they note "maximum 2 s" for type C generating units), while the full activation time is 30 s at most [6]. This active power surplus has to be provided for 15–30 min depending on the type of generating unit and the agreement achieved with the TSO.

Apart from the requirements regarding primary reserves, the network code introduces the concept of *synthetic inertia* [6]. Synthetic inertia means replicating the inertia of a synchronized generating unit using a non-synchronized generating unit, i.e. a wind power plant. Providing synthetic inertia with the methods available today is not identical to instantaneous reserves. However, it is an approximation, which is helpful and may be crucial for system stability.

With the aim of contributing to the frequency stability of the electrical system, ENTSO-E encourages TSOs to set, in the future, requirements for wind power plants (both onshore and offshore) for providing synthetic inertia under low frequency events. In particular, it implies injecting power proportional to the "severity"[3] of the disturbance in a very short time (200 ms) [6].

Hydro-Québec TransÉnergie recently researched the synthetic inertia needs [23]. The analysis quantifies the impact on frequency performance and stability of the inclusion of new 2000 MW of wind power into the Hydro-Québec transmission system. Simulation results show that in order to maintain system frequency within its operating limits under a low frequency disturbance (58.5 Hz) and thus avoiding automatic load shedding, wind farms have to participate in frequency regulation by providing synthetic inertia. It is worth highlighting that the minimum duration of active power contribution for synthetic inertia is set to 10 s (considering 6% of active power increase) in order to expand the contribution beyond the frequency nadir. This is important, since finishing the provision of synthetic inertia in the very first seconds of the frequency disturbance, before achieving the new steady state of frequency after the disturbance, could increase the frequency nadir further, as it can be intended as a further loss of generation during the transient. The results of this research are consistent with results of [24], which determines that the synthetic inertia provided by wind turbines can help to avoid the activation of underfrequency automatic load shedding as higher frequency nadir are registered during a frequency disturbance.

Another option for wind turbines to at least partly compensate for missing instantaneous reserves in the system is, besides synthetic inertia, a very fast frequency response (according to a power–frequency droop characteristic) with very short time response and time delay [25]. The next section will review and discuss methods for both the provision of primary frequency control and of synthetic inertia.

3. Participation methods of wind power plants for primary frequency control and synthetic inertia

3.1. Deloading methods of wind turbines for primary frequency control

Conventionally, wind turbines are operated at maximum aerodynamic efficiency, so that they can maximize the power extracted from the wind. At the partial-load region, the speed of the turbine is controlled by the regulation of the aerodynamic torque (or power) [26], leading the so-called optimal torque rotor-speed curve. In particular, the optimal aerodynamic power is computed by

$$P^{*} = K_{cp}(\beta) \cdot \omega_t^2, \tag{4}$$

where ω_m is the speed of the turbine, K_{cp} is the so-called optimal aerodynamic torque coefficient and depends on the aerodynamics of the turbine and the pitch angle β. Usually this curve is implemented in a look-up table in the controller of the machine

[2] The ENTSO-E definition of these terms is different from the definition in the UK regulations. ENTSO-E's code requires a wind power plant to ramp up its active power output during under-frequency events, but UK regulations (see Section 2.4) require the wind power plant to maintain a constant active power output.

[3] This requirement is not defined in further detail in the grid code [6].

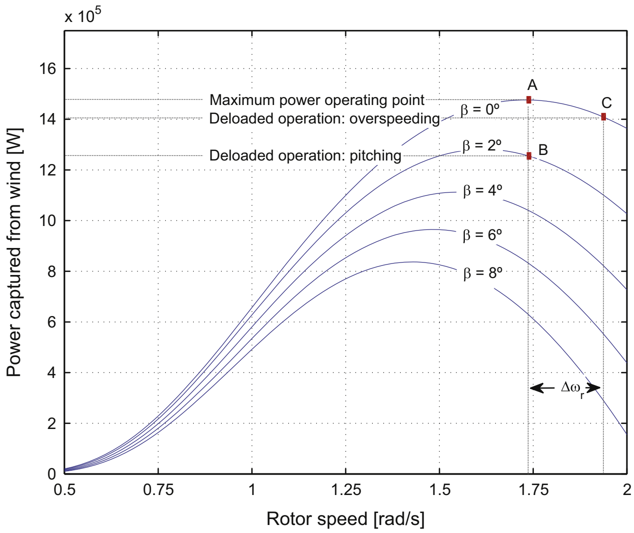

Fig. 7. Power rotor-speed curves for different values of pitch angle and deloaded options for a 1.5 MW wind turbine (wind speed: 10 m/s).

side power converter of the wind turbine, leading the so-called maximum power tracking algorithm (MPT).

For maximum power generation, β is maintained constant at zero degrees in partial-load operation of the turbine. In contrast, in full load operation, the generator torque is kept constant and the pitch control is activated in order to limit the power captured from the wind and thus to not exceed the turbine rated power [27–29,35]. The pitch angle can be regulated e.g. by a PI controller, which is governed by the difference between the turbine rated power and the actual measurement [30]. Controlling the rotor speed at constant torque can be a possibility for driving this PI controller, as well [36]. Further, it is interesting to note that pitch angle may also be varied cyclically in order to mitigate mechanical loads of the turbine [37].

As noted in Section 2, wind power plants are required to participate in primary frequency control by ramping their output up and down according to a power–frequency droop characteristic and during a certain period of time. This means that wind turbines either have to be operated in a deloaded mode, or a suitable energy storage device has to be available. This article focuses on solutions for the first method. Different approaches can be found in the literature on the subject of deloading methods of wind turbines, which can be classified into two main categories: pitching techniques and overspeeding techniques [2,32].

Both methods are based on the idea of achieving a non-optimal working point in the torque–rotor-speed curve of the turbine (or, analogous, in the power–rotor-speed curve). As it can be noted in Fig. 7, deloading is then realized by using C (overspeeding the turbine) or B (pitching the blades) as standard operating points and switching between point A and additional deloaded points.

While applying pitching techniques, the rotating speed of the turbine is kept constant (point B). Conversely, while applying overspeeding techniques, the turbine is operated at a higher rotor speed, while keeping the pitch angle constant (point C). One main difference between these two strategies is the fact that overspeeding can only be applied in variable speed wind turbines (i.e. DFIG-based and full-converter-based wind turbines).

Underspeeding techniques are not preferably applicable. A deceleration of the rotor from point A in order to reduce the active power output would transiently lead to an increase of active power. This is due to the fact that the rotor releases kinetic energy. At the same time, when moving to point A from an underspeed level, the rotor would transiently consume active power for acceleration. Small signal stability could be also endangered (unlike with respect to pitching techniques) [31].

Depending on the wind speed level, either the one method or the other (pitching or overspeeding) is advantageous. Three different operating regions for wind turbines can be considered in this sense: low, medium and high wind speed ranges. In low wind speed range, wind turbines operate at partial load. Thus, the rotating speed of the turbine does not reach its rated value at any time, allowing the application of overspeeding techniques. In medium wind speed range wind turbines mostly operate at partial load but they can achieve their rated rotational speed transiently, and thus the pitch controller may be activated. In this region, a combination of overspeeding and pitching techniques may be a good option for deloading the wind turbine. And finally, in high wind speed range pitch control becomes a key factor for both limiting the power extracted from the wind in order not to exceed the ratings of the generator and for applying deloading strategies. Instead of only limiting the power, it can be used for ramping power up and down. Overspeeding strategies generally do not fit well in this region. Apart from the limitations regarding wind speed for applying the above-mentioned deloading strategies, further related considerations can be found in the literature that must be taken into account for application of the deloading strategies mentioned. A brief summary of some of them is presented in Table 2.

The following subsections deal with a literature review regarding the application of each of the aforementioned strategies.

3.1.1. *Control basis of overspeeding and pitching techniques for the deloaded operation of wind turbines: an example*

Fig. 8 visualizes a general example for a controller structure which allows deloading and participation in frequency control by pitching and overspeeding techniques. It serves as the basis for the literature overview of the proposed methods. Considering low wind speeds and rotor speeds below rated, deloaded operation is preferably carried out by means of overspeeding techniques (i.e. by affecting the power reference to the power converters of the wind turbine). For wind speeds near or above nominal, when maximum rotor speed is reached, the pitch controller is additionally activated.

As shown in Fig. 8, the deloaded power reference P_{ref} of the wind turbine can be obtained from the sum of the available active power of the turbine (which depends on the wind), P_{av}, and the output of a primary frequency control droop ΔP. The computation of P_{av} can be carried out using internal signals of the turbine and will not be discussed in detail here.

A decision algorithm coordinates the activation of pitching and overspeeding techniques. It transfers the reference P_{ref} to the pitch control in case it is being used, and also translates P_{ref} and P_{av} into the requested power margin reference x. x is the reference for the applied overspeeding technique. It is important to note that even while regulating the pitch angle, it is still necessary to control the power extracted through the converters of the wind turbine, so it is still necessary to determine a reference x consistent with the reference P_{ref} for the pitch control.

In the case of deloading the wind turbine through pitching techniques, the pitch angle is driven by a PI controller, which tries to minimize the difference between the measurement of the generation level and the deloaded power reference P_{ref}.

The so-called deloaded optimum power curves are the key aspect for the implementation of the overspeeding techniques. The following contents explain the basis of this element; see Fig. 9. Applying the conventional control approach according to Eq. (4), the target operating points lie on the optimum power curve in the $P-\omega$ diagram. In contrast, for deloading and participation in frequency control, the target operating points lie on a deloaded curve, which corresponds to the requested power margin x. The

Table 2
Considerations regarding deloading strategies of wind turbines.

Overspeeding techniques
• Method preferably applied to below rated wind speed levels [29].
• Wind speed measurements are usually required for determining the maximum power that a wind turbine could extract from wind while applying the deloaded power–rotor speed curves. Accuracy and reliability of this wind speed measurement are crucial [30].
• Considering DFIG, the percentage of power transmitted through the set of back-to-back power converters becomes greater with greater values of slip. This limits the overspeeding of the wind turbine in order not to overcome the ratings of the power converters [29,31].
• Danger of excessive mechanical stress in the rotor shaft due to the fast deloading through the fast torque control for speed regulation. Need of limitations of rate of change of torque [28].
• Rotor speed regulation is only possible in variable speed wind turbines.
• Due to the inertia of the rotor, the power ramping is not linear.
Pitching techniques
• Method preferably applied to above rated wind speed [29].
• Excessive pitch control actions may lead to tear and wear of the mechanism [28,32]. Moreover, pitch angle regulation could affect fatigue life of the blades as it affects their dynamic loads [33,34].
• Larger time responses than in overspeeding techniques due to pitch servo time delays [31].
• Usually, no wind speed measurements are required [35].

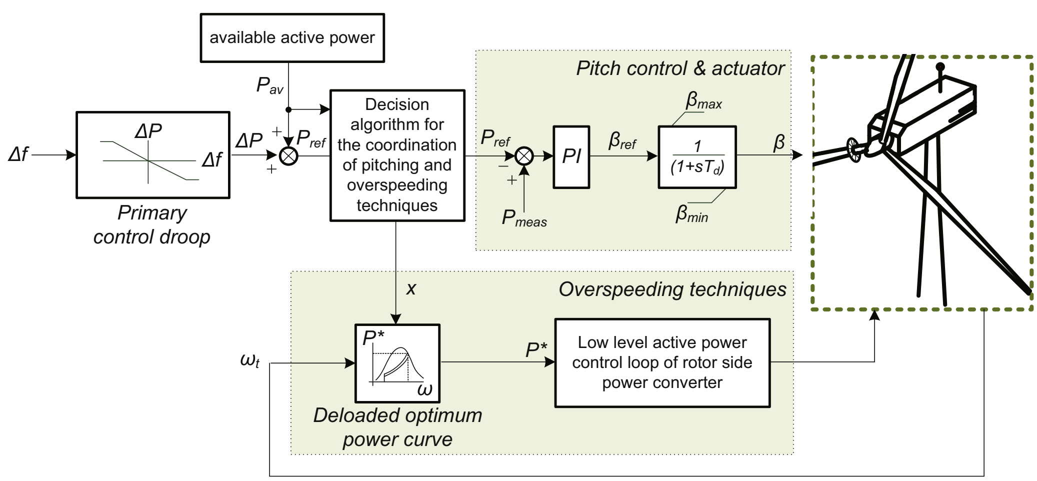

Fig. 8. Example of a control scheme for a wind turbine for primary frequency control support. It includes the primary frequency control droop, the pitch control and the rotor speed control.

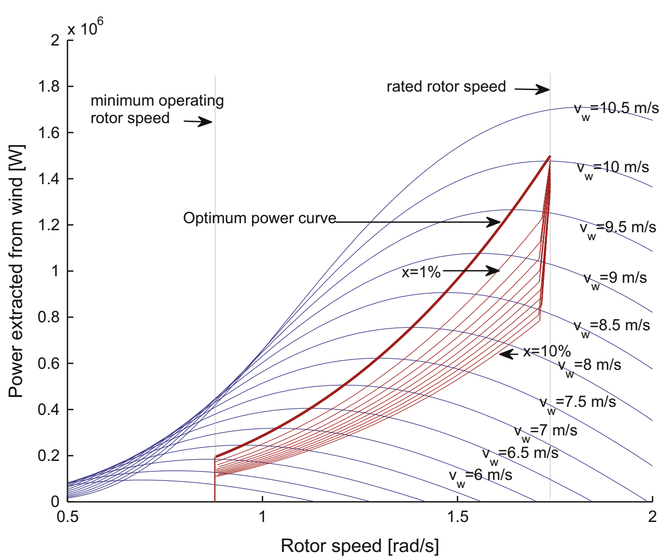

Fig. 9. Deloaded optimum power curves for deloaded operation of a 1.5 MW DFIG-based wind turbine.

power curves can be pre-calculated. Thus, the power reference to the generator controller is retrieved from the measured turbine speed ω_t, the required power margin and the power curve diagram.

The principle of deloaded optimum power curves is adopted in [33,39–42] and [43]. The deloaded power curves as depicted in Fig. 9 can be precalculated as follows. The active power set-point of the wind turbine $P_{del_{opt}}$ is related to the maximum available power P_{opt}, which is computed from Eq. (4) and the required power margin x, as

$$P_{del_{opt}} = P_{opt}(1-x). \tag{5}$$

For this desired power level, a corresponding sub-optimal power coefficient $C_{p_{del}}$ can be computed for a specific wind speed as

$$C_{p_{del}} = \frac{P_{opt}(1-x)}{0.5\rho A v_w^3} = C_{p_{del}}(v_w, \omega_t, \beta). \tag{6}$$

The power coefficient of a wind turbine is a function of pitch angle, wind and rotor speed. Thus, for a given pitch angle and wind speed, a rotor speed can be determined, which corresponds to the required sub-optimal power coefficient. By means of these operations, a family of deloaded optimum $P-\omega$ curves can be defined, as plotted in Fig. 9.

The torque reference can be also computed instead of the active power reference by applying torque–omega curves instead of power–omega curves.

3.1.2. Review on overspeeding and pitching techniques for deloaded operation of wind turbines

The previous section presented the basis for overspeeding and pitching techniques for wind turbines, whereas this one reviews

the literature on control techniques for enabling wind turbines to participate in frequency control related tasks. The studies introduced cover several aspects as different methods to perform the required speed and pitch angle regulation for wind turbines, the combination of both techniques for different wind speed regions, and the coordination of the power reserves of several wind turbines by wind power plant central controllers.

In [34] a look-up table containing the curves in Fig. 9 is used to determine the power set-point which drives the low level active power control system of the rotor side converter of the generator while applying overspeeding techniques. This look-up table takes the required power margin and the rotor speed measurement as inputs. No wind speed measurements are required. The determination of the power set-point in above rated wind speed region is carried out by means of a second look up table, which takes into account the required power margin and the pitch angle measurement. It also takes into account cubic interpolation between close pitch angles due to their large influence on the aerodynamic behavior of a wind turbine. Finally, it is noteworthy that overspeeding and pitching actions are not carried out at the same time, but overspeeding only applies when the pitch angle is set to zero.

Approaches which take wind speed measurement as input can also be found in the literature. For instance, in [33] it is proposed to access to the optimum power curve using wind speed as input and determine the optimum power reference P_{opt} and its corresponding optimum rotor speed ω_{opt}. From these signals and the required power margin x, one can determine the deloaded optimum generating point. In this way, accuracy and reliability of wind speed measurements become key issues for the implementation of the proposed control strategy. However, wind speed measurement on top of the nacelle is not really reliable when it comes to representing free wind speed due to influences by the rotor.

Another approach proposes combining rotor speed and pitch angle regulations at the same time in below rated rotor speed range [40]. The idea is to control the above-mentioned parameters in order to maintain a required deloaded level of the wind turbine. Thus, when a frequency drop occurs, wind turbine shifts both the pitch angle and rotor speed references towards their optimal values (i.e., it shifts pitch angle to a minimum value and rotor speed according to the optimal power curve of the wind turbine). It is worth pointing out how the set-points of rotor speed and pitch angle are determined in order to provide the required power reserve. Given a required deloaded power level, the deloaded aerodynamic power coefficient $C_{p_{del}}(v_w, \omega_t, \beta)$ can be determined applying Eq. (6). For each wind speed, $C_{p_{del}}(v_w, \omega_t, \beta)$ is influenced by the selected combination of ω_t and β, and there is more than one possible combination. This allows a combination with maximized ω_t to be chosen, which means maximizing the kinetic energy stored in the rotor. This is realized by means of an optimization procedure. As this procedure is complex and time-consuming, the results obtained offline were extrapolated to a suitable online strategy. It is worth highlighting that wind speed measurements are required for implementing this control algorithm. When a frequency drop occurs, and due to high initial rotor speed, the speed regulation of the wind turbine deals a large amount of kinetic energy injected to the grid in the first seconds of the frequency excursion. The aforementioned strategy only applies to below rated rotor speed range. For near or above rated wind speed levels, in order to avoid exceeding the rated rotor speed level, only pitch control is used to realize the turbine power reference. As a result of the maximization of the kinetic energy injected in the first seconds of the frequency disturbance, the frequency nadir is delayed in time and its value is higher than in the case of applying a deloaded strategy without this kinetic energy support. However, it is worth noting that the fast power regulation means large loads on the shaft of the turbine.

The idea of taking advantage of the kinetic energy stored in the rotating parts of a wind turbine while in deloaded operation is further investigated by the authors of [40] in [41]. Here, new control algorithms are presented for both pitch angle and rotor speed that allow the maximization of the kinetic energy in the rotor in order to improve the frequency control support. It is worth noting that both articles conclude that using the kinetic energy stored in the wind turbine reduces the need of deloaded operation while still providing the required amount of power for a short time frame. This time frame is considered to be the maximum deployment time of 100% of primary reserves according to the ENTSO-E's requirements [11], i.e., 30 s (see Table 1).

Deloaded operation of wind turbines which also take into account the interaction with wind farm central controllers are examined in [33,44,45]. It is worth noting that reliable and fast SCADA systems with a sampling rate of 1–3 s for frequency measurements should be adequate, considering the desired reaction time of wind turbines [31].

In [33], the dispatch function of wind farm central controller is based on the solution of an optimization problem, which sets adjustments of active and reactive power set-points for each wind turbine so as to optimize the power flow within the wind park, i.e. to minimize active power losses while participating in frequency control related tasks.

In [44], a wind farm active and reactive control system, which provides power set-points for each wind turbine, is also considered. Once local control of a wind turbine receives the active power set-point from the central controller, two situations may happen. It could happen that wind speed is high enough, and therefore, it is possible to achieve the required generation level. Then, a PI controller is driven by the error between the active power set-point and the measured power signal. The output of this PI is the required pitch angle. Therefore, the turbine is always operated at the maximums of the pitch angle curves of Fig. 7, while the PI controller chooses the pitch angle curve. While computing the pitch angle, a MPT algorithm computes a speed reference from the power generation measured. Since the output power is reduced by the pitch controller, the MPT algorithm outputs a speed reference below its optimal value, dealing reduced values of tip speed ratio and C_p power coefficients and then, helping wind turbine to reduce its generation level. On the other hand, if wind speed is not high enough to achieve the required generation level, the pitch angle is saturated at its minimum value maximizing the power extracted from the wind. It is deduced that deloaded operation can also be carried out with control techniques presented in this article. Note that this article does not analyze the stability issues derived from the interaction between the PI controller for pitching the turbine and the central control system of the wind power plant that sets out the active power reference for the wind turbines.

The following paragraphs focus on the description of pitching techniques according to a literature review. A pitching technique for deloaded operation is presented in [8]. Pitch regulation is defined for two regions: region A (above rated power output), and region B (below rated power output). In region A, the active power output of the turbine is usually limited to its rated value by setting a non-minimum pitch angle. However, the turbine is deloaded in this case through a further pitch angle increment. In this manner, it is possible to ramp the output of the turbine up and down for frequency regulation. In region B, the active power control scheme of the rotor side converter controller is commonly commanded by a MPT algorithm [26] (considering variable speed wind turbines). In this region the pitch angle is usually set to its minimum value in order to extract the maximum power from the wind. However, in this article the pitch angle is also regulated in response to the measured frequency to the change in frequency in a narrow band

of ± 2 degrees. In detail, a frequency-pitch angle droop characteristic is applied. This narrow pitch angle regulation band deals up to 400 kW of power spill for a 2 MW DFIG-based wind turbine.

In [38], the proposed deloaded technique is applied to DFIG and PMSG-based wind turbines. As the power extracted from the wind is linear dependent on the power coefficient C_p, a defined percentage reduction of power generation can be achieved by reducing in the same proportion C_p (see Section 3.1.1). The wind turbine is always operated with an optimal tip speed ratio λ_{opt} (and thus with an optimal C_p when no deloaded operation is commanded). This means that a reduction in C_p from its optimal value can be achieved by determining a non-minimum pitch angle β. This pitch angle is mathematically computed using the relation

$$C_p(\lambda_{opt}, \beta) = (1-x)\% \cdot C_{p,opt}(\lambda_{opt}, \beta_{min}). \quad (7)$$

Knowing the desired load percentage reduction x, λ_{opt} and $C_{p,opt}$, the desired value of $C_p(\lambda_{opt}, \beta)$ is determined. Again with given λ_{opt}, the required pitch angle β can be determined. Below rated wind speed, the required power margin is achieved by applying the calculated pitch angle. Above rated wind speed level, this computed pitch angle is added to the conventional PI pitch controller, which is in charge of limiting the rotor speed to its rated level.

Finally, it is important to note that the contribution of offshore wind power plants to main grid frequency control support is also investigated. For instance, [46] considers an offshore wind power plant connected to the grid via a Voltage Source Converter-Based High Voltage DC link (VSC-HVDC). The wind power plant is composed of full converter wind turbines. The objective is to regulate the output of the wind farm in response to main grid frequency variations. The power output of the wind turbines is governed by the offshore side VSC of the HVDC transmission and this converter does not receive any measurement of the main grid frequency. In order to communicate information on the main grid frequency, the VSC terminal on the onshore side ramps the voltage level of the HVDC transmission up and down proportional to the frequency deviation. Results show that the offshore wind power plant can greatly support the grid frequency control during grid disturbances. The used deloading method of the wind turbines is not discussed.

3.2. Synthetic inertia

As discussed in Section 2.5, in order to promote high penetration levels of wind power into the grid without compromising frequency stability, wind power plants may be required in future to provide synthetic inertia [25]. Providing this means replicating the behavior of synchronized generating units with respect to power imbalances in the grid. This can be achieved by introducing control schemes which detect grid frequency variation and command according to active power feed-in. Both the dynamics and the dependency on frequency should be similar to the behavior of synchronous generators. However, the details have not been clearly defined as yet. As described in Eq. (2), the additional electrical power fed in by synchronous machines during frequency changes (i.e. generator deceleration) is proportional to the derivative of their mechanical rotational speed ω_g. This means that for wind turbines, the additional active power (or torque) should be proportional to the derivative of the grid electrical frequency df/dt.

According to [47] and [48], typical wind turbine inertia constants are between 4 and 6 s. These values are comparable with the normalized inertia constant of conventional generating units (between 2 and 9 s depending on the type of generator). Using the fact that the rotor speed of variable speed wind turbines is not coupled to the grid frequency, the deceleration of the rotor can be chosen by the controller. This allows a trade off between the additionally provided power and the duration. Generator speed of conventional synchronous generating units varies directly with frequency, i.e., for variations between 47.5 and 52.5 Hz, it stays within 0.95–1.05 p.u. In contrast, the generator speed of wind turbines can vary down to 0.7 p.u. This means that wind turbines can use more than 4 times the capacity of regulation of the kinetic energy of conventional synchronized generating units [2]. However, a recovery strategy for the proper rotational speed of the wind turbines after their deceleration for synthetic inertia is required.

The initial loading, i.e. the initial rotor speed of wind turbines, has great influence on their provision of synthetic inertia as the kinetic energy depends on the square of the rotational speed (see Eq. (3)). Additionally, the ratings of the converters of the turbine [1] have to be taken into account for the evacuation of the kinetic energy through these power electronics.

In normal operation, wind turbine torque is governed by the maximum power tracking (MPT) algorithm that does not react to changes in system frequency. However, the following paragraphs discuss several control approaches for torque to respond to system frequency in order to provide synthetic inertia.

In [42], a control system for synthetic inertia is proposed. Fig. 10 depicts its topology. As shown, the upper path (MPT) contains the conventional determination of the generator torque reference as explained in Section 3.1. Moreover, the loop L1 is in charge of additionally providing an offset torque signal proportional to the ROCOF, e.g. a positive, decelerating torque signal if the frequency drops. This decelerating torque signal lasts until the frequency stabilizes. Then, without the support of any additional control action, the overall torque reference T^*_{elec} would decrease, as the MPT aims to lead the system back to the optimal curve. This would obviously reduce the power injected to the grid transiently and thus take back the frequency support provided directly. Even though recovery of the original turbine speed is necessary, the process should be carefully planned. In particular, recovery should happen slowly, with enough time for the primary frequency controllers in the grid to react.

In order to avoid this re-acceleration of the turbine, the regarded control system also includes a second loop L2. It is worth noting that this is not, however, commonly found in the literature. This is in charge of providing an additional torque signal proportional to the frequency deviation Δf, so its output lasts until the nominal frequency level is recovered. Note that this loop L2 is not actually the same as the droop of the primary frequency control as it provides a torque (not a power reference) depending on Δf.

Ref. [49] adopts the previously presented control system for synthetic inertia. It is noticed, talking in terms of Fig. 10, that both K_1 and K_2 are varied regarding the loading level of the wind turbine. It is done because, as discussed in the article, inadequate control parameters can cause unstable operation of the wind turbine. For instance, excessive value of proportional parameter K_2 under low wind conditions can cause wind turbine to stall

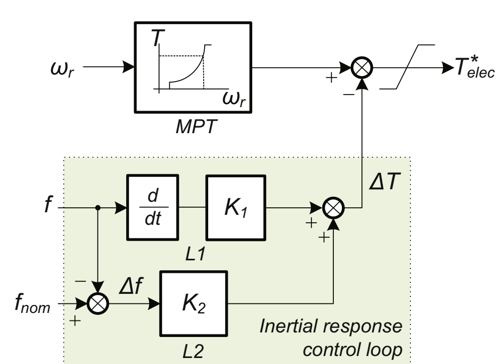

Fig. 10. Determination of the electromagnetic torque set-point from a MPT algorithm and additional control loop for synthetic inertia. Plot adopted and adapted from [42].

because of excessive extraction of kinetic energy. The control scheme also considers a recovering strategy for the wind park to lead the turbines back to their initial operating point. This recovering strategy is based on instructing each wind turbine to switch off their frequency support at different times.

Two different control methods for synthetic inertia are proposed in [46]. The first method is composed of simply the control loop L1 in Fig. 10. However, a low-pass filter is added after obtaining the frequency derivative signal. The aim of this filter is to avoid high rates of changes in the torque set-point obtained due to noise in frequency measurement. These undesirable excessive torque variations cause mechanical loads in the drive train and may also exceed the current limits of the power converters of the wind turbine. The second control method comprises the second loop L2 in Fig. 10. This article is devoted to comparing the performance of the above-mentioned control methods under the event of a system frequency disturbance. It is concluded that the droop control of loop L2 deals lower increase in active power than the synthetic inertia provided by loop L1. This results in lower over-currents and mechanical stress for the wind turbine. Needless to say, this assertion depends on the considered magnitude of parameters K_1 and K_2.

A new synthetic inertia approach is offered in [50]. This method relies on a conventional primary frequency control scheme, but performed in a fast manner. Therefore, the aim is not explicitly to let the wind turbine behave similar to a conventional generating unit. However, the turbine does provide frequency support in the same time frame as synthetic inertia would. To do that, a droop characteristic (in MW/Hz) is used to obtain a power reference signal, which is added to the output of the conventional MPT algorithm. In this article, a washout filter is applied to the signal Δf (in order to reject the constant component of the signal), so the input of the power / frequency droop characteristic is zero as soon as the steady state is achieved.

It is worth pointing out that this article also considers the interaction of the fast power regulation of wind turbines with the primary frequency controllers of their near conventional generating units. The fast response of wind turbines following a network power imbalance can slow down the response of conventional generators to some extent. This is because the fast additional power injection of wind turbines partly compensates the power network unbalance (affecting the network frequency). However, their support lasts for a few seconds and then, conventional generators, which did not notice the real magnitude of the power unbalance from the beginning of the disturbance, are required to act to recover the network balance by full activation of their power reserves. In order to overcome this response delay of conventional generating units, a communication scheme between them and wind turbines is proposed.

This article also offers a comparison with the previously mentioned synthetic inertia depicted in [42]. In regard to this comparison, care should be taken in setting the above-mentioned proportional characteristic K_2 (see Fig. 10), as higher values of this parameter can affect the oscillatory modes of an interconnected system. On the contrary, the implementation of the wash-out filter for the frequency in [50], favors the mitigation of these oscillatory modes.

Finally, in [48], an approach for provision of synthetic inertia by a wind farm is proposed. Despite the fact that partial load conditions are considered for the analysis, the active power output of wind turbines is adjusted by both the pitch angle and the power converters. In the event of a derivative of frequency, the park controller commands an increment in active power set-points to the local controller of the power converters of each wind turbine. After 3 s from the activation of this power increase, a slow recovering process to the initial state of wind turbines is performed. This slow recovering process is carried out by delaying the particular recovering process of each wind turbine individually. Accordingly, each wind turbine injects an increased level of power for a specific time frame. This strategy smooths the net power injected by the wind farm during the recovering process, which can last for up to 30 s. It is worth noticing that no aggregated model of the wind farm is used in order to allow an individual recovering process for each wind turbine and to also take advantage of the spatial smoothing effect of the wind farm.

4. Conclusions

The following conclusions are extracted from the contents of the article:

- Current Grid Codes of islanded European networks like UK and Ireland already consider the participation of wind power plants in primary frequency control. In this sense, they require wind turbines to be operated not extracting the maximum available power from wind. They have to be operated in a deloaded mode instead, in order to be able to ramp their output up and down in the event of a frequency deviation.
- On the other hand, other regulations of strong European electrical grids like the German grid, do not consider the operation of wind turbines in a deloaded mode in normal operating conditions. For instance, the German Grid Code only requires that wind turbines reduce their power injection in the particular case of overfrequency.
- Future trends for European regulations like the recent European Network Code developed by the ENTSO-E, indicate the need of deloading wind turbines to participate in primary frequency control. Therefore, it is concluded that in the near future the provision of power reserves by wind turbines for their participation in frequency control related tasks will be required not only for islanded grids, but also for strong continental grids.
- Currently, Grid Codes of islanded European networks require that wind turbines be derated by up to 20% of the theoretically available power and for periods of time up to 30 min in the event of a negative frequency deviation. In case the frequency level is within the normal operating limits, wind turbines have to maintain a deloaded level up to 10% of the maximum available power.
- In the literature, two major methods for deloading wind turbines can be found: pitching methods and overspeeding methods. Both methods are based on the idea of achieving a nonoptimal working point with respect to power extraction from the wind.
- Each of the aforementioned strategies fits best with different wind speed levels. For low and medium wind speed levels, considering that the rated rotor speed is not achieved, overspeeding techniques are preferable. Pitching techniques are best suited considering that the rated rotor speed is achieved.
- Among the articles consulted, approaches can be found that consider the measurement of the wind speed for developing overspeeding techniques. As this measurement is typically not reliable, its application is considered problematic. Moreover, when applying overspeeding and pitching techniques additional mechanical stresses have to be considered for turbine components such as the generator shaft and the pitch actuators.

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